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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON ADMINISTRATIVE LAW JUDGE'S RULING ON GREENHOUSE GAS EMISSIONS ACCOUNTING METHODS AND ADDRESSING UPDATED GREENHOUSE GAS BENCHMARKS

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I. INTRODUCTION

Pursuant to the directions set forth in the *Administrative Law Judge's Ruling Seeking Comment on Greenhouse Gas Emissions Accounting Methods and Addressing Updated Greenhouse Gas Benchmarks* ("ALJ Ruling") issued on April 3, 2018 (April 3rd Ruling), the California Community Choice Association ("CalCCA") respectfully submits the following comments on the ALJ Ruling.

CCAs are on the vanguard of meeting renewable energy and state Greenhouse Gas ("GHG") reduction goals while also serving our communities with tailored programs that reflect community needs. For example, Peninsula Clean Energy already provides its customers with energy that is generated from 50% RPS-eligible resources and is 85% GHG free. As partners with the state in meeting both RPS and GHG reduction goals, CalCCA's members agree with the general goals expressed in D.18-02-018 that state policies be developed that ensure actual emissions reductions and that those emissions are aligned with serving of load.[1] All CCAs have a general incentive to match supply and load as misalignments create exposure to market price risk. When engaging in resource planning processes, CCAs are attentive to such risk and carefully consider related imbalance exposure along with the procurement costs associated with available clean energy product options. In fact, some CCAs integrated resource plans already require this matching of supply and load to occur over time.[2] CalCCA greatly appreciates the formal and informal conversations initiated by the Commission's staff thus far on how to achieve both of those goals via the GHG emissions accounting methodology. However, the manner in which we collectively meet these two goals is critically important and care must be taken that unintended consequences do not result from hasty decisions or the use of flawed methodologies that influence sub-optimal procurement decisions.

To avoid such outcomes, any proposal for GHG emissions accounting must align with the GHG and Renewable Portfolio Standards ("RPS") requirements set in Senate Bill ("SB") 350, other state agency efforts and responsibilities, and the Commission's RESOLVE model. In addition, any proposal must be analyzed for ratepayer impacts prior to consideration. The CNS proposal creates significant concerns precisely because it is inconsistent with the RPS, other state agency efforts and the RESOVLE model and will likely have a negative impact on ratepayers across the state. The proposed methodology also undermines early action already taken by Load Serving Entities ("LSEs"), contrary to AB32, by devaluing after the fact the GHG attributes of resources already acquired by LSEs (primarily resources meeting Portfolio Content Categories 2 and 3) and for which these LSEs had made long-term committments. Accordingly, CalCCA has

[1] See D.18-02-018, p. 119.
[2] See, e.g. Peninsula Clean Energy, Integrated Resource Plan, available at:

significant concerns with the current Clean Net Short ("CNS") proposal and urges the Commission to go a different route.

CalCCA recommends that the Commission adopt, at this time, a procurement-based methodology that is consistent with the RPS program and incorporates the common and long-standing use of Renewable Energy Credits ("RECs") accounted for in the Western Renewable Energy Generation Information System (WREGIS) as the primary means to verify carbon reduction. CalCCA supports the ultimate goal of adopting a more granular emissions accounting methodology, because it will align emissions reductions with serving load, but the current methodology is not the right solution and a transition to a new accounting framework must be carefully considered and developed to avoid potential distributional impacts.

While a procurement-based accounting system is urged at this time, if the Commission determines that CNS is the appropriate methodology, then the Commission should adjust the accounting and reporting of an LSE's GHG emissions from an hourly basis to an annual basis. The CNS should also be modified to acknowledge the renewable and GHG-free attributes of all RPS-eligible resources, including those resources that are located outside of a California Balancing Authority Area, regardless of contract structure.

II. <u>THE COMMISSION MUST ESTABLISH A GHG EMISSIONS CALCULATION METHODOLOGY THAT IS CONSISTENT WITH THE POLICY GOALS SET BY SENATE BILL 350</u>

Senate Bill ("SB") 350 set several ambitious goals for California's electricity sector. These goals include:

1. Meeting the GHG emissions reduction targets set by the ARB to 40 percent from 1990 levels by 2030.

2. Procuring at least 50 percent eligible renewable resources by the end of 2030, consistent with the existing RPS statute.
3. Minimizing the impacts on ratepayers' bills.

The responsibility for achieving these goals is divided amongst LSEs. The ARB is responsible for setting the system-wide and individual LSE GHG reduction targets, and Commission's responsibility is to develop a planning process to guide LSEs to achieve these goals.

In adopting a GHG emissions calculation methodology, the Commission must balance the goals set by SB 350. A methodology that is inconsistent with any of the policy goals will create renewable resource procurement uncertainty and increase costs for ratepayers. While the Commission may see the adoption of a GHG emissions calculation methodology as a stand-alone goal, the methodology will directly impact renewable energy markets, resource valuation, procurement and planning process, and costs for ratepayers.

III. <u>RESPONSES TO QUESTIONS IN ALJ RULING</u>

1. Are the basic steps of the accounting methodology described in Attachment A and the associated GHG calculator tool internally consistent and technically sound? Why or why not? Identify any flaws in the method that are likely to have a material impact on long-term planning and explain how these deficiencies should be addressed.

No, they are not consistent. As explained in further detail below, the CNS proposal is inconsistent with the ARB's GHG emissions calculation methodology, thereby undermining the ARB's authority to set GHG targets and frustrating coordination on state greenhouse gas efforts. It is also inconsistent with the existing RPS law, as it strips away the environmental attributes from Portfolio Content Category ("PCC") 2 and PCC 3 resources, devalues PCC 1 resources on a temporal basis, and penalizes LSEs that have made early investments in renewable resources.[3] Furthermore, there is no state mandate or previous Commission determination that LSEs have to structure their supply portfolios to match their load profiles at an hourly level of granularity. Indeed, the entire RESOLVE modeling process is based on developing an optimal system-wide approach to GHG reductions. Adopting a methodology that upends the flexibility afforded under the current regulatory frameworks for meeting the RPS and GHG reduction requirements without careful consideration and minimal justification is inappropriate.

a. The CNS Proposal Is Inconsistent with the ARB's Proposed GHG Targets for the Electricity Sector.

SB 350 assigns to the ARB the responsibility for setting the GHG targets for both the electric sector and each individual LSE. The ARB's latest proposal for setting individual LSE targets is to base the target on the ARB's cap-and-trade allowance allocation methodology.[4] This is the same methodology the Commission itself proposed when it adopted its interim GHG targets for each LSE.[5]

This methodology relies on an annual, not hourly, calculation of an LSE's GHG emissions. The ARB's cap and trade allocation methodology assumes an LSE meets its 50% RPS target, and then provides additional allowances reflecting the remaining mix of resources. The ARB's methodology gives full credit to an LSE for all of the RPS-eligible energy it procures. It is not limited, as it would be under the CNS proposal, solely to the RPS-eligible energy procured that exactly matches the LSE's load and is only procured from PCC 1 resources. Adoption of the CNS proposal would thus create a fundamental contradiction between how the target is set (using one

[3] The Commission's portfolio would devalue PCC1 products by requiring that their generation match the LSE's load that is claiming them for RPS compliance, specifically excludes PCC3 and PCC3 products, and devalues PCC1 products already procured but banked for future use.
[4] ARB staff presentation for SB 350 Integrated Resource Plan Workshop, March 2, 2018.
[5] D. 18-02-018 at page 124-127.

methodology by the ARB), and how achievement of that target is met (using a different methodology that contains a different metric for measurement).

It would be exceedingly difficult, if not impossible, for the Commission to reconcile this inconsistency. It would require taking the ARB's adopted targets, set on an annual basis, and converting these into hourly requirements to determine what CARB's targets would be under a CNS approach.[6] . Moreover, if the Commission keeps an hourly reporting metric, the Commission would essentially be setting its own GHG targets for each LSE, targets that are different than what the ARB has adopted. This outcome is directly at odds with SB 350's requirement that the ARB, and not the Commission, sets the GHG targets.[7] In creating this situation, the proposed CNS methodology usurps and undermines the ARB's authority to set the GHG target.

b. The CNS Proposal Is Inconsistent with the RPS Program.

One of the requirements of the Commission's IRP planning process is to ensure that California's LSEs meet their RPS compliance obligations. Under the RPS program, there is no requirement that RPS-eligible energy claimed by an LSE for RPS compliance must be matched up in real-time with the LSE's load. Instead, the goal of the RPS program was to reduce emissions and develop the renewable market by granting LSEs credit for all RPS-eligible energy and attributes they provided to the electric grid.[8] The assumption of the RPS program, similar to the RESOLVE model, is that any additional GHG-free or RPS-eligible energy provided to the grid benefits California. The RPS compliance framework was also set up flexibly to mitigate concerns

[6] Conversion would require developing an assumed hourly demand forecast for each LSE, as well as hourly forecasts for each supply source the LSE is using to meet that demand. For some of these supply resources, there would be no hourly forecasts as the ARB methodology assumes a LSE procures the necessary RPS-eligible resources to meet its obligation but does not specify which technology (each of which have different generating profiles) are acquired to meet this requirement.
[7] Public Utilities Code Section 454.52(a)(1)(A).
[8] Public Utilities Code Section 399.13(a)(3) states that the Commission should direct each retail seller to submit an RPS compliance report annually.

over the ratepayer impacts. Moreover, the electricity of eligible renewable resources may be generated outside of a California Balancing Authority Area, as long as it is generated in the Western Interconnection, to comport with the United States Commerce Clause.[9] The relevant RPS statute further prohibits the discrimination against resources located outside of California.[10] The CNS proposal upends this entire framework by unilaterally determining that GHG-free PCC 2 resources and PCC 3 RECs will not count for GHG reductions. This determination runs directly against clear prohibitions on discrimination and directly thwarts the flexibility contained in state law for meeting the RPS without any stated rationale or reason. To comply with SB 350, LSEs need to procure resources in a manner consistent with the RPS program – which utilized a REC based accounting system conducted on an annual basis – to achieve the GHG emissions reduction. The GHG emissions calculation methodology must also be consistent with this underlying framework of the RPS, otherwise LSEs can risk meeting one policy goal at the expense of not meeting another. The proposal may also run afoul of the Commerce Clause to the extent it treats RECs with the exact same attributes under state law differently based on the location of their generation.

c. The CNS Proposal Unfairly Penalizes LSEs that Lead in Promoting GHG Reductions while Rewarding those that Do the Bare Minimum.

As noted above, the CNS proposal also conflicts with both the underlying methodology the ARB uses to calculate the electricity sector-wide emissions and discourages LSEs from taking leadership in investing in new renewable resources. An extreme example can best illuminate the concern. First, assume an LSE has an annual load of 3,000 GWh/year as well as a supply portfolio consisting of strictly PCC 1 wind resources with an output of 3,000 GWh/year. While this LSE

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[9] Public Utilities Code Section 399.11(e)(1).
[10] Public Utilities Code Section 399.11(e)(2).

clearly relies on system power when the wind is not blowing, it provides excess wind energy during the evening ramp when system demands are high. The excess wind energy also lowers the overall GHG emissions of the grid due to the investment by the LSE. Under current RPS and ARB accounting frameworks, on an annual basis, the LSE is 100% GHG free, with the output of its wind resources covering its total yearly load. This LSE would also report its 100% RPS-eligible renewable portfolio to the Commission. This annual GHG emissions calculation is the same methodology that is used by the ARB to allocate cap-and-trade allowances, which is the basis for the 42 MMT scenario constraint adopted by D. 18-02-018.[11] [12] RECs would be retired by the LSE so that all of the carbon emissions benefits accrue to the customers who are paying for the GHG-free solar power.

However, under the CNS proposal, the LSE with the 100% GHG-free wind portfolio would only be able to claim GHG attributes associated with the fraction of wind generation that was less than or equal to its load on an hourly basis. The excess wind generation would continue to lower the overall emissions of the grid, however, as the resources within the portfolio would still be generating wind energy. This outcome would significantly devalue the wind resource, as the RECs associated with excess generation above load would become stranded and the LSE would receive no GHG credit for the excess wind power that was provided to the grid in excess of its load. Even more troubling, the LSE that invested in the wind resources – demonstrating leadership in producing more renewable energy under the RPS than necessary, would see the benefit of its investment and leadership transferred to other LSEs. Thus, an LSE that did the bare minimum within the RPS would receive a direct and material benefit via a lower system-average GHG

[11] D. 18-02-018 at page 120.
[12] D. 18-02-018 at page 58 reads "Cap-and-Trade program is the ultimate compliance tool for ensuring a direct reduction in GHG emissions economy wide in California."

emission rate. This outcome would incentivize free-ridership and disincentivize LSEs from pursuing more ambitious GHG reduction goals, ultimately for the greater overall system-wide GHG reduction. This free-ridership and disincentive to decarbonize the grid is directly contrary to AB 32's statutory requirements that voluntary action be accounted for within California's GHG framework. Within the particular context of CCAs, who are demonstrating leadership in procuring renewable resources above state requirements, this outcome would directly disincentivize the very local action the ARB has specifically recognized as *essential* for the state to meet its GHG reduction goals.[13] Such outcomes must be avoided at all costs if the state is going to meet its aggressive climate goals at the lowest possible costs. The CNS proposal undervalues PCC 2 firmed and shaped resources even more harshly by disallowing the use of their RECs merely based on the location of the facility out of state. Such an outcome runs directly contrary to Section 399(e)(2) and the Commerce Clause.

d. It Is Unclear if Any LSE Could Claim to Be 100% GHG-Free Under the CNS Proposal.

Under the CNS Proposal, no LSE could claim to be 100% GHG-free unless it was able to exactly match its load with its zero-GHG generation for all 8,760 hours of the year. One proposed option to remedy this problem would be for the LSE to acquire sufficient storage capacity to exactly balance its generation with load. However, this scenario was not directly modeled in the IRP proceeding, and is not part of the adopted IRP planning scenario, thus the cost and feasibility of this approach is not part of the record. The closest the Commission came to considering, and

[13] For example, the 2008 Scoping Plan noted: "Local governments are essential partners in achieving California's goals to reduce GHG emissions." Scoping Plan at pg. 26; see, also 2017 Revised Scoping Plan (recognizes that that local efforts can deliver substantial "additional GHG and criteria emissions reductions beyond what State policy can alone.") October 27, 2017. p. 145.

rejecting this approach, is in the adopted IRP's discussion that it was cheaper to curtail RPS-eligible generation rather than invest in additional storage.

e. Adoption of the CNS undermines California's efforts to promote Green Tariff and roof-top solar

The adoption of the CNS approach would severely undermine the Commission's efforts to promote behind-the-meter solar and Green Tariff Shared Renewable ("GTSR") programs. One of the stated goals of the IRP process is to ensure consistent inputs and metrics among all resource types, including distributed generation through such approaches as the Common Resource Valuation Model (CRVM). Under the CNS approach, virtually all of these solar incentive and GTSR programs could not claim to be "100% GHG free."

While the Commission has not intended for the CNS to be a customer disclosure methodology, data that are made public through this proceeding will likely be interpreted as such. Instead of conveying to customers the 100% GHG-free investment that they have made through the premiums embodied in their rates, marketing materials for these customers would need to be adjusted to reflect the partially GHG-free content that is consistent with the CNS.

To the extent the CNS proposal devalues the GHG reduction values that these resources provide, it also could make it harder for the Commission to justify further investments in and support for these programs.

f. The CNS Proposal Is Inconsistent with the RESOLVE Model.

The CNS model is inconsistent with the underlying RESOLVE model that is driving all of the resource procurement assumptions in the IRP decision. As described in the Reference System Plan ("RSP"), the RESOLVE model seeks to optimize the entire electric system for CPUC-jurisdictional LSEs. Units are dispatched based on marginal cost and/or GHG emission profile without any consideration of either fixed cost recovery or assignment of GHG reductions to any particular LSE. Nothing in the model imposes a new constraint that an LSE only receives credit for the generation that matches its load. Instead, as the RESOLVE model states: "The value proposition of integrated resource planning is to reduce the cost of achieving GHG reductions by looking across individual LSE boundaries and resource types to identify solutions that might not otherwise be found."[14] Had the model been run with this constraint imposed, the resulting procurement outcomes would likely have been significantly different, and the cost of the adopted RSP would likely have been significantly higher.

The theoretical result, according to the RESOLVE model, is the optimum and least cost electric system that meets California's GHG reduction goals. Attempting to superimpose an after-the-fact requirement that each LSE must meet its own GHG reduction goals in real-time negates the validity of the RESOLVE model's results. The RESOLVE model's dispatch protocol, which aims to dispatch all resources regardless of ownership to minimize GHG emissions is also consistent with the other constraints that LSEs already operate under.

These constraints include market signals, including the California Independent System Operator's ("CAISO") Locational Marginal Prices, to structure and schedule supply portfolios that match their load profiles. While CalCCA appreciates the intent to strengthen reliability incentives, GHG emissions calculations are not the right tool for reinforcing grid reliability.

g. *It is unclear what problem, and the magnitude of the problem that the CNS proposal is trying to solve*

The Commission has yet to provide a rationale as to what problem, and the magnitude of the problem that the CNS is trying to solve. The contention appears to be that LSEs that provide excess GHG-free energy to California's electric grid somehow shift a GHG burden to other

[14] Reference System Plan, p. 16

LSEs. The overall net impact of this problem is never calculated or shown. To use as an example a LSE with significant solar generation, in many hours of the day surplus solar generation provided to the grid allows gas-fired generation to back down. During the night, gas-fired generation might be needed to meet the LSE's demand. Nowhere in the CNS proposal is the net effect determined.

On a MWh basis, the effect is likely to be a wash as reduced natural gas generation during the day would likely equal, or perhaps exceed increased natural gas generation at night. For GHG-emission calculation purposes, the Reference System Plan itself determines there actually would be a net gain, as night-time load (being less than day-time load) is likely to be met by more fuel-efficient lower GHG gas fired generation on the margin. Use of inefficient high-GHG peakers during the day is also likely reduced by providing surplus GHG energy to the grid.

As the Reference System Plan concluded;

- The vast majority of electric sector emissions result from CCGTs [gas-fired generation] because they run more hours during the year;
- New renewables selected by RESOLVE [almost entirely solar] primarily displace CCGT use during <u>day-time hours</u> (emphasis added)…; and that
- The largest opportunity to reduce air pollutants from the electric sector is by reducing the use of CCGTs. [15]

Thus it appears that the overall quantification of the overall <u>net</u> effect is to improve GHG reductions, even if generation does not match each LSE's individual load. As noted above, the RESOLVE model specifically ignores individual LSE ownership in dispatching resources.

2. What impacts might using the method described in Attachment A and the associated calculator tool have on an individual LSE's long-term resource investment decisions? Provide any suggestions for how the

[15] Reference System Plan, p. 10

method could be modified to reduce or eliminate any negative impacts identified.

a. Adoption of the CNS Proposal Will Result in Significant Cost Increase.

With the GHG-free value of PCC 2 products eliminated, LSEs would have to exclusively procure PCC 1 resources to meet their 50 percent renewable energy requirements while also meeting the GHG emissions targets set by the ARB. LSEs would also be precluded from including in their GHG calculations, existing GHG reductions from their previous (and in many cases long-term) investments in PCC 2 resources. While LSEs could procure hydroelectric and nuclear resources to meet their GHG emissions targets under the CNS proposal, the Commission needs to be aware of the availability of hydroelectric resources, at least for non-IOU LSEs, which are an increasing part of state procurement, as well as some CCA governing boards' zero-nuclear procurement mandates.[16] Based on the paucity of instate hydroelectric resources available to non-IOU LSEs, distributional impacts of the CNS must be considered, particularly if they may negatively impact the growth of CCAs, which as a matter of state policy has been determined by the Legislature to be in the state's interest. Moreover, given the scarcity of instate hydroelectric resources for non-IOUs, it is reasonable to assume that if the Commission adopts the current version of the CNS proposal, the resource procurement costs for new LSEs would increase dramatically.

According to a memorandum by City of Palo Alto's Utilities Department, PCC 1 REC alone costs $15/REC, compared to $6.50/REC for PCC 2 RECs, and $1/REC for PCC 3 RECs.[17] Based on this data, PCC 1 resources cost at least twice as much as PCC 2 resources, not accounting

[16] CCAs with no nuclear procurement mandate include for example Marin Clean Energy ("MCE"), Peninsula Clean Energy ("PCE"), Silicon Valley Clean Energy ("SVCE"

[17] Memorandum on Renewable and Carbon Neutral Portfolio Strategy Discussion, December 6, 2017. https://www.cityofpaloalto.org/civicax/filebank/documents/62466

for the purchase of energy, which is more expensive in California than in other states.[18] Combining the cost of RECs and the cost of energy, all California ratepayers will likely see a significant increase in their electricity bills if their LSEs have to forgo the purchases of PCC 2 and PCC 3 resources.

In addition, requiring hourly accounting increases the likelihood of economic curtailment of some resources, particularly solar, as baseload production and solar resources would converge to meet shifting daytime demand. Curtailment will drive up costs for ratepayers even further, while negatively impacting in-state solar resources.

If the Commission must adopt the CNS proposal today, without considering a transition, the proposal should be: 1) modified to include PCC 2 resources in the definition of "GHG-Free", and 2) modified to an annual (as opposed to hourly) calculation to avoid the outcomes described above. The Commission should also adjust several modeling assumptions, including using average GHG emissions instead of the currently proposed marginal emissions to avoid over-counting emissions on the grid. The methodology should also avoid assuming that clean resources will be curtailed any time they exceed the individual LSE's hourly load, as such assumption does not necessarily align with the CAISO market signal on a given day.

b. The CNS Proposal Is Inconsistent with the Ability to Use Banked RECs to Meet RPS Compliance and GHG Reduction Goals.

The adopted IRP decision recognizes that LSEs have the ability to use banked RECs to meet their GHG reduction goals.[19] The vast majority of these banked RECs are PCC1 RECs

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[18] "Costs and Benefits of U.S. Renewable Portfolio Standards." International Association for Energy Economics Energy Forum, Third Quarter 2014, September, 2014. https://emp.lbl.gov/publications/costs-and-benefits-us-renewables

[19] D. 18-02-018 at page 41.

associated with California-based generation and for which the LSEs (primarily the IOUs) that have acquired these resources expected to be able to rely on for meeting RPS and GHG reduction goals.

It is unclear how to reconcile a CNS approach that requires an LSE to match its generation and load in real time in order to receive GHG reduction credit, with the ability of LSEs to use banked RECs, accumulated years previously, to simultaneously be credited toward GHG reductions.

CalCCA supports the use of banked RECs counting toward GHG compliance. As noted in CalCCA's reply comments to the Proposed Decision,[20] the ARB's concern is with achieving cumulative GHG reductions not with hitting a specific point-estimate GHG target.

Not allowing LSEs to count banked RECs essentially assigns a zero value to these RECs. It also undermines the symmetry between the RPS compliance regime and the IRP process as well as increasing costs for these LSE's customers.

3. Does the method in Attachment A hinder or improve the state's ability to achieve its long-term GHG emissions reduction goals? Explain your answer.

The CNS proposal would hinder the state's ability to achieve its long-term GHG emissions reduction goals by penalizing new renewable resource investments in California and beyond. As explained in CalCCA's responses to the last two questions, the CNS proposal eliminates the GHG-free value of PCC 2 and PCC 3 resources based merely on the locations of those resources, and only partially credits PCC 1 resources with GHG-free attributes only when those resources match an LSE's load at a very specific time during a specific day. These rules are a significant departure from the state's RPS mandate and the Commission's own program, which have guided all LSEs' procurement investment. Furthermore, there is no justification for not crediting or partially

[20] D.18-02-018 at page 49

crediting GHG-free attributes to these current resources when LSEs have already paid the premium that acknowledges the GHG-free attributes of these resources.

First, excluding PCC 2 and PCC 3 power from the definition of GHG-free power is directly contrary to current industry practice of GHG emissions calculation. Whether wind power is generated in Oregon, Wyoming or California, it is zero-emissions power, and it is consumed in the Western Interconnection and who gets to claim the energy produced is based on RECs. There is no way to know where the power is consumed, nor is there any guarantee that it is consumed locally, nor does it matter from a GHG perspective. All that matters is that GHG-free power served load, thereby avoiding the need for power from other GHG emitting resources. This is critically important as SB 350's goals are a reduction in GHG emissions from the electric sector. The only administratively reasonable way to account for such reductions is via RECs.

Therefore, excluding PCC 2 and PCC 3 power from the definition of GHG-free is not logical, and hurts California customers by forcing LSEs to procure more expensive in-state PCC 1 resources that bear the same GHG-free attributes as cheaper firmed-and-shaped resources. Furthermore, this could disincentivize LSEs from procuring PCC 2 and PCC 3 resources, and instead procure fossil fuel energy from out of state, which would receive the same GHG emission treatment as PCC 2 and PCC 3 resources under the current proposal. For example, instead of procuring a PCC 2 geothermal resource, which is RPS-eligible and therefore more expensive, an LSE can choose to reduce their costs while obtaining the same emissions factor by procuring cheaper out-of-state coal or natural gas resources.

Second, partially discounting PCC 1 resources' GHG-free attributes also hurts investment in in-state renewable generation. It is important to note that as more loads depart for CCAs, CCAs are going to be responsible for building new renewable resources in California. These renewable resources are important for CCAs because many CCAs have RPS and GHG-free goals—set by their local governing boards—that are above and beyond the state's requirement.[21] Some CCAs also have an interest in investing in local renewable resources to create local jobs and reduce local air pollution. Providing the LSE that built, and is paying the cost of these new resource, with only partial credit for the GHG-free attributes of this renewable resources (to the extent the new resources' generation exactly matches the LSEs load) would harm investments that have been made and jeopardize investments in new renewable resources.

4. *Do you agree or disagree with the characterization of renewable energy credits related to compliance with the renewables portfolio standard program and their relationship to IRP's GHG emissions goals in the proposed methodology in Attachment A? Explain why or why not.*

It is pertinent to distinguish between source emissions and emissions associated with delivery. Because it is impossible to track electricity and determine where is power is consumed, emissions associated with retail electricity delivery can only be measured based on who procured the resource and assumed the corresponding cost, based on Renewable Energy Credits ("RECs"), which can only be created when one MW of renewable energy has been generated and put on the grid. RECs can only be retired when renewable energy delivery has been confirmed by matching e-tags, which come with the electricity, and the RECs. Because a REC can only be generated when a MW of renewable energy has been generated, and that an LSE can only claim renewable energy delivery once an e-tag matches a REC to trigger a REC retirement, RECs are a reliable accounting tool to verify that renewable energy has indeed been generated and put on the Western grid. RECs

[21] CleanPowerSF plans to achieve an RPS content of 50% by 2020, and increase GHG-free resources in its portfolio each year to achieve the City and County of San Francisco's goal of a 100% GHG-free electricity supply by 2030. East Bay Community Energy, which will launch in June 2018, plans to offer a basic product that is 85% GHG-free. Marin Clean Energy aims to have a GH G-free portfolio by 2025. Peninsula Clean Energy has strategic goals of 100% GHG free electricity by 2021 and 100% from RPS eligible resources by 2025. Silicon Valley Clean Energy offers electricity products that are 100% GHG-free with a minimum of 50% RPS eligible renewables. Sonoma Clean Power plans to reach 50% RPS by 2020.

are a uniform contractual tool that facilitates transactions, tracking, and compliance, and they represent the delivered electricity's emissions profile.

It is important to note that all of the IOUs have used the REC-based accounting system for reporting GHGs from retail electric sales through the third-party validation process at The Climate Registry.[22] This process explicitly recognizes both PCC 2 and PCC 3 as zero emission, but allows a retail seller to voluntarily exclude PCC 3 from reported volumes. The difference between power plant emission reporting and retail sales reporting is very important: power plant emissions are traceable to a specific source since they occur before energy enters the grid. Thus, a REC based accounting system is verifiable and traceable. Retail sales emissions must be tied exclusively to the contract for payment or ownership arrangements because they cannot physically be traced by any other means. Hence the system of RECs was established to ensure that only those who pay for GHG benefits have the right to report those benefits.

CalCCA believes a procurement-based accounting methodology, which utilizes REC verification for GHG emissions accounting, is the most reliable and verifiable, and administratively least burdensome. However, if the Commission is determined to adopt the CNS proposal, then the proposal should be adjusted to recognize the inherent GHG-free attributes embodied in a REC.

5. Provide any suggestions for improving the GHG calculator tool.

Please see CalCCA's response to question 2

6. Comment on any specific aspects of the methodology in Attachment A with which you disagree and explain your proposed alternative approach.

Please see CalCCA's response to questions 1 and 2

[22] "Independent Registry Confirms Record Low Carbon Emissions for PG&E." March 26, 2018. http://www.pgecurrents.com/2018/03/26/independent-registry-confirms-record-low-carbon-emissions-for-pge/

7. ***Describe any alternative GHG accounting methodology that the Commission should consider adopting for IRP purposes and explain why the alternative is preferable to the method described in Attachment A.***

While CalCCA sees the value of adopting a methodology that encourages LSEs to conduct procurement that closely resemble their loads, as stated above, such methodology is contrary to SB350's requirements that it is the ARB and not the CPUC that sets the GHG reduction target; will create significant impact on the renewable energy market, and impede LSEs' ability to meet the 50% RPS goal in 2030 if not handled properly over time. CalCCA proposes that the Commission adopt a procurement-based approach for emissions accounting, which is verifiable and consistent with the Commission's existing and successful RPS program.

Under the procurement-based approach, LSE-specific emissions would be calculated based on delivered electricity to customers, which would incorporate accounting for REC retirement. As explained above, RECs are the most reliable and least administrative burdensome approach to ensure that LSEs have indeed invested in renewable and GHG-free energy, and that the energy has indeed been delivered to the grid and the customers in California.[23] Under such an approach, all RPS-eligible resources, as well as hydro and nuclear resources, would receive GHG-free emission treatment. Such an approach would recognize both the past investment made by LSEs to reduce GHG emissions and increase RPS resource investment, and would ensure that LSEs can make future cost-effective investments that minimize the impact on ratepayers. A contract-based approach would also be consistent with the RPS program, and prevent litigation related to the violation of the Commerce Clause. CalCCA also recommends that the Commission provide a

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[23] This is verified because the generation is either located in, or directly connected to a California balancing authority, or the use of e-tags address deliverability of resources outside the balancing authority.

workshop where alternative approaches, including the procurement-based approach suggested by CalCCA, can be further examined and refined by a broader range of stakeholders.

However, if the Commission believes that the CNS is the right methodology, and must be implemented at this time rather than after more consideration of the issues described above, CalCCA strongly suggests that Commission staff making the following edits (redlined below) to the GHG accounting methodology proposed in the ruling.

1. *The LSE will subtract out any owned or contracted non-dispatchable GHG-emitting resources (such as non-dispatchable combined heat and power (CHP) or fossil imports) it plans to use to serve its ~~hourly~~ annual load from its projected ~~hourly~~ annual electricity demand in 2030.*

2. *The LSE will subtract its owned or contracted (either current or planned) GHG-free generation from the projected ~~hourly~~ annual electricity demand, less the amount subtracted in the previous step.*

a. *"GHG-free" generating resources: RPS Bucket 1, RPS Bucket 2, hydroelectric, and nuclear generation, if delivered to ~~a California balancing authority area~~ the Western Interconnection.*

b. *"GHG-emitting" generating resources: any resources other than those deemed GHG- free above.*

3. *The LSE will subtract the discharging pattern (and add the charging pattern) of any storage resources owned by or contracted to the LSE from the ~~hourly~~ annual profile derived in step #2. The result is the "clean net short" (CNS) ~~in each hour~~ for the year.*

4. *The CNS will then be multiplied by the system GHG emissions intensity ~~on an hourly basis~~ for the year, yielding total emissions associated with using unspecified system power for that LSE for ~~every hour of~~ 2030.*

5. *Finally, the emissions from all owned or contracted non-dispatchable GHG-emitting resources used to serve ~~hourly~~ annual load in step #1 will be computed using plant-specific emissions factors and added to the emissions from unspecified system power calculated in step #4.*

8. Comment on any other aspect of the methodology in Attachment A that was not already covered in the previous questions, explaining your rationale and suggested modifications.

CalCCA does not have comments on other aspects of the methodology in Attachment A.

IV. CONCLUSION

CalCCA thanks Assigned Commissioner Randolph and Assigned Administrative Law Judge Fitch for the opportunity to provide these comments on the ALJ Ruling.

Respectfully submitted,

/s/ Beth Vaughan

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